A Risk-based Financial Valuation for Cross-border Electricity Transmission Interconnections

Applied to the East Africa Power Pool (EAPP) Eastern Corridor Ethiopia-Kenya Interconnector

World Bank Summer Internship Project

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Summary

The purpose of this modeling exercise is to demonstrate a risk-based financial valuation of the cash flows of a cross-border electricity transmission interconnection. This type of analysis is important because it enables decision makers to make informed design and financing decisions based on their understanding of the project's all-in costs and impact on customers.

In this analysis, the Ethiopia-Kenya Interconnector is being evaluated as a stand-alone project. The focus of this analysis is therefore to understand the enabling cash flows of the selected interconnection project over its lifetime. The main benefits that are attributable to the Interconnection are those revenue streams that are enabled because of it, viz. power-purchase agreement (PPA) based and other trade flows of electricity. Demand uncertainty is the most significant and primary source of risk to the project because it drives the volume of electricity trade over the transmission interconnection, the very reason for wanting to build the interconnection in the first place. The benefits of the project are realized only when the trade flows and the corresponding financial flows are realized.

The design of the ET-KY Interconnector features an important real option which has real economic value. The transmission line can be designed so that its transfer capacity can be increased in the future. This analysis demonstrates that having the expansion option is valuable, in both low and high trade scenarios.

The analysis finds that power-purchase agreement based revenues cover only a small fraction of the cost annuity required to pay for the Interconnection. Even though the tariff supplement necessary to maintain cost annuity equilibrium is significant, the postage-stamped tariff adders for retail demand in the interconnected systems are low. Further, the tariff supplement required is highly sensitive to the level of PPA trade and the corresponding bulk tariff, and extremely sensitive to the fraction of capital costs bought down. Low levels and growth rates in short-term trade of energy reduce the tariff supplement moderately but are far from sufficient to eliminate the tariff supplement. Therefore, a very high level of PPA trade is required at low bulk tariff levels for the Interconnection to be financially viable. Finally, the phased design is the most valuable design option under both low and high levels of trade, because it results in a cost savings when trade is low and enables high levels of trade at a very small cost increment if demand increases significantly after the line becomes operational.

Objective

The purpose of this modeling exercise is to demonstrate a risk-based financial valuation of the cash flows of a cross-border electricity transmission interconnection. The type of investment project under consideration is any transmission interconnection that is being proposed for connecting isolated or unconnected networks, such as in the case of two adjacent countries' electricity systems that have not been previously interconnected. This type of analysis is important because it enables decision makers to make informed design and financing decisions based on their understanding of the project's all-in costs and impact on customers.

The Ethiopia-Kenya (ET-KY) Interconnector is chosen for applying this methodology, because of its importance as a critical project in the Eastern Africa Power Pool, and the availability of project-specific data from several feasibility studies. The proposed interconnector will enable firm delivery of electricity from Ethiopia to Kenya in the short-term and support regional electricity trade in the region in the mid- to long-term. The financial implications of the project should therefore be assessed with both short and long time horizons in mind – selecting only one or the other may lead to uninformed conclusions about the project's financial viability.

A Note on Transmission Project Valuation and Transmission Planning

In this analysis, the ET-KY Interconnector is being evaluated as a stand-alone project. That is, we ignore other generation and transmission projects that may eventually be developed in the relevant electricity systems. The project should be viable on its own merits, irrespective of how the rest of the system evolves. We take a different approach than a typical transmission expansion plan for three important reasons.

First, the project has already been determined to enhance (social) welfare in the combined systems. The comprehensive system-wide economic cost-benefit analysis that is characteristic of a least-cost transmission planning exercise has already been produced.[1] The Interconnection's regional economic benefits have been adjudged to outweigh its costs based on a variety of system development scenarios in Ethiopia and Kenya, and the EAPP region. However, such planning studies do not address the financial flows attributable to the transmission line. We want to understand the patterns of costs that have to be incurred and revenues that must be realized to make the Interconnection financially viable as a stand-alone project. The focus of this analysis is

[1] See SNC-Lavalin International and Parsons-Brinckerhoff (May 2011), "*Verification of the Regional Economic Robustness of Ethiopia-Kenya Transmission Interconnection Options for the Development of the EAPP*" and Fichtner (February 2009) "*Ethiopia-Kenya Power Systems Interconnection Project Final Feasibility Study Report*"

therefore to understand the *enabling cash flows* of the selected interconnection project over its lifetime.

Second, only cash flows directly attributable to the ET-KY Interconnector project must be analyzed in its financial valuation. Although the Fichtner (2009) report conducts a financial analysis, it lumps *avoided* generation projects with the Interconnection wherein the avoided costs of generation and fuel are considered benefits accruing to the transmission line. As a result, the cost and tariff implications of the interconnection by itself are somewhat obscured. While this approach is reasonable in a system-wide expansion plan, it is erroneous to assume that a particular generation project is avoided because of the transmission interconnection, unless the two projects are being explicitly compared as mutually exclusive projects. The approach was appropriate when the interconnection was considered an integral part of the Gibe III hydro project. However, in the Eastern African Power Pool, there is no certainty about which proposed generation projects will be avoided or realized as a consequence of the Interconnection as a stand-alone project and in fact, there may even be additional generation investments motivated by the opportunity to trade electricity across the interconnection. In any case, the main benefits that are attributable to the Interconnection are those revenue streams that are enabled because of it, viz. contract-enabled and other trade flows of electricity. The benefits of the project are realized only when the trade flows and the corresponding financial flows are realized. By neglecting all other hypothetical and planned generation and transmission investments, this financial valuation focuses on the cash flows of the interconnection alone.

Third, the design of the ET-KY Interconnector features an important *real option* which has real economic value. The transmission line can be designed so that its transfer capacity can be increased in the future. The project entity has the option to defer capacity expansion until just before additional capacity is needed, such as in the case when there is a high demand for electricity trade across the interconnection. This design approach avoids capacity underutilization early on in the life of the project when retail demand is still low, thereby decreasing project costs. While the previous feasibility and economic studies acknowledge and discuss the existence of this design option, they do not demonstrate the financial implications of having this option, which is explicitly done here. This analysis demonstrates that having the expansion option is valuable, in both low and high trade scenarios.

Key Assessment Metrics

Under a regulated framework[2], the costs (capital, operating and financing) of the transmission project will be recovered either directly from "users" of the transmission line, i.e. generators that

[2] That is, where a regulated monopoly network utility undertakes network expansion projects, as opposed to merchant transmission developers. In the regulated setting, transmission revenues can be assured by including a transmission tariff or wheeling charge in the long-term power purchase agreement for firm power

wheel power over it and traders engaging in short-term firm transactions, or indirectly passed through to end-use retail customers in the systems being interconnected. The primary outputs of this analysis are those that illustrate the cost implication of the transmission project, and consequently the effect on retail electricity tariffs, if any. Specifically, the key outputs are selected as:

- The "all-in" cost of the transmission project, annuitized over the project's economic life (Million USD/year), that must be recovered
- The tariff supplement required (Million USD/year), or the difference between all-in cost annuity and the revenues to the project, to reach equilibrium with the cost annuity
- The tariff impact (+/- c/kWh), if any, on end-use retail tariffs that is attributed to the interconnection project in the event of under recovery through direct user revenues.

As discussed below, the magnitude of the annuitized costs and tariff impact depends on some risk factors and a number of assumptions.

Uncertainty and Risk

Demand uncertainty is the primary risk factor considered. Although there are many sources of "risk" to a project of this nature, such as cost overruns, equipment failure, schedule delays, and ancillary system issues such as generator unavailability, most of these risks can be understood and managed through appropriate planning and good industry practice. However, the uncertainty in growth and volatility of retail demand in the two systems being connected is the one important exogenous source of uncertainty that affects the financial considerations of the project. Demand uncertainty is the most significant and primary source of risk to the project because it drives the volume of electricity trade over the transmission interconnection, the very reason for wanting to build the interconnection in the first place. The magnitude of both long-term power purchase agreement based trade and short-term surplus trade are sensitive to retail demand uncertainty. The effect of uncertain demand on the project is quantified by measuring the tariff supplement required and the impact on retail end-use tariffs, as described below.

Uncertainty does not always have a negative implication, since it can often make projects more valuable in NPV terms. Often, there exist "real options" in the design of a project that may make it more profitable under uncertainty. In this case, the design consideration is whether to build a line with a large capacity up front, or use a design that features an "option to expand" later on during the life of the project. This design option is explored fully in the valuation model. It allows consideration of capacity utilization and cost minimization under uncertain evolution of retail demand, and therefore the level of trade.

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transactions. In the merchant model, revenues are realized by price arbitraging across the two ends of the line making use of the fact that supply and demand constraints create a price differential in the two systems.

Modeling Approach

This section describes the approach to the modeling analysis is a series of high-level steps, as shown in Figure 1. The model can be constructed in a variety of ways - the high level principles are captured here to illustrate the logic, so that other analysts can use their own models to compare results.

Figure 1. Four Step Process for Measuring Tariff Impact

(1) Determine the Cost Annuity for the Stand-Alone Project

The critical first step is to determine the all-in cost of the transmission project. The all-in cost includes the

- Base capital expenditure of the line
- O&M costs of the project over its lifetime, and
- Financing costs such as loan commitment fees and interest expense.

The all-in cost is annuitized over the life of the project to result in an annual cost that must be incurred by the project entity (utilities or others) to realize the project. The all-in cost is therefore sensitive to a number of assumptions such as the base costs, interest rate, discount rate, etc.

Cash Outflow $_{\text{year } t}$ (\$) = {Capital Expense + O&M Expense + Financing Costs} $_{\text{year } t}$

All-in Costs (\$) = {Present Value [Cash Outflow $_{\text{year } t}$] } over project life

=> Cost Annuity (\$/year) = {All-in Costs (\$) x Annuity Factor [discount rate, project life] (/year)}

(2) Assess Annual Revenue for Assumed Trade

The second step is to incorporate a revenue stream to the project entity that depends on the level of trade. The trade revenue stream has two sub-components. (i) The first is a long-term Power Purchase Agreement (PPA) that serves as a trade anchor of firm electricity delivery between the interconnected systems. The PPA is essentially a mechanism to secure the commitment for firm future trade and must be negotiated before project construction begins. By charging a bulk tariff to electricity wheeled over the line as an "access tariff" a stable revenue stream is realized. In the model, the level of firm long-term trade in the PPA and the resulting revenue stream can be examined to determine the sensitivity of the PPA to tariff impact on retail demand. (ii) The second component is comprised of short-term firm bilateral trades of surplus electricity. Such transactions are also assessed a tariff as a service charge and provide an additional revenue stream, although the level is expected to be low initially and volatile over the project life.

PPA payments $_{\text{year } t}$ (\$/year) = {Bulk tariff (\$/MWh) x PPA trade volume (MWh/year)} $_{\text{year } t}$

Service Charge Payments $_{\text{year } t}$ = {Access Charge (\$/MWh) x surplus trade volume (MWh/year)} $_{\text{year } t}$

=> Revenues $_{\text{year } t}$ (\$/year) = {PPA Payments + Service Charge Payments} $_{\text{year } t}$

(3) <u>Identify Tariff Supplement</u>

The interconnector's revenues come from trade transacted over it; however trade is uncertain over the life of the project, especially surplus electricity traded in the short term. The revenue streams from both PPA-based and short-term trades may not cover all the incurred costs of the project leading to a "missing money" problem. The missing money will have to be recovered from retail demand in the two interconnected systems as a tariff supplement such that costs and revenues are in equilibrium. The yearly tariff supplement is the difference between the cost annuity and the realized revenues in that year.

Cost Annuity (\$/year) = {Revenues + Tariff Supplement} $_{\text{year } t}$ (\$/year)

=> Tariff Supplement $_{\text{year } t}$ (\$/year) = {Cost Annuity – Revenues $_{\text{year } t}$ } (\$/year)

(4) <u>Calculate the Postage-stamped Tariff Adder</u>

Once the tariff supplement (missing money) has been identified, it is allocated to retail demand in the interconnected systems on a postage stamp basis. The country supplement – share of the total tariff supplement allocated to each country – is allocated on a per kWh basis. Thus, all retail end-users in the interconnected systems see a transmission tariff adder (increment/decrement).

Country Supplement (\$/year) = {Country Allocation Fraction (%) x Tariff Supplement $_{\text{year } t}$ (\$/year) }

=> Country Tariff Adder $_{\text{year } t}$ (c/kWh) = {Country Supplement $_{\text{year } t}$ (\$/year) / Aggregate Retail Demand (MWh/year)} $_{\text{year } t}$

The four step process described here is the essence of the modeling process. The next sections discuss some of the main parameter values assumed in the model.

The Transmission Interconnection – Technical Assumptions

The Ethiopia-Kenya Interconnector is a critical element of the Eastern Africa Power Pool. The interconnector is important not only for the feasibility of electricity trade between Ethiopia and Kenya in the short term, but also for supporting transactions between other member countries of the EAPP in the mid- to longer-term. Table 1 summarizes the main design features necessary for representing the project in the model.

For a number of technical and economic reasons, the recommended technology for this project is a 500 kV bipolar HVDC line. Depending on the final route selected, the line may run to a length of 1000 – 1200 km.

Table 1. ET-KY Interconnector Design Features for the Risk-based Financial Valuation

Transmission Line Specifications for Valuation Model	
Type	500 kV HVDC Bipolar
Length	~ 1100 km
Rated Capacity	2000 MW
Design Options	(1) Unphased: 2000 MW operational in 2017, or (2) Phased: 1000 MW as Phase 1 operational in 2017, option to add 1000 MW thereafter as Phase 2
Construction Time	4 years for both unphased option and Phase 1 of phased option; 2 years for Phase 2 capacity addition
Load Factor (for PPA)	80% of 300 MW for 8760 hrs/year
Operating Life	25 years, 2017 - 2041
Base Costs	(1) Unphased: USD 1 billion (2) Phased: USD 820 million in Phase 1; plus USD 240 million if Phase 2 implemented
O&M Expense	2% of Base Costs

As introduced earlier, there are two main design options available, primarily involving the capacity of the interconnection. The first is an "unphased option" in which the 2000 MW of power transfer capability including the line, converters, towers, and necessary grid reinforcements are installed up front and the line commences operation in 2017. In the second flexible or "phased" option, the line is built with the conductors and towers for 2,000MW of capacity but initially only half of the converter and transformation capacity is installed and operational by 2017. The option to add another 1000 MW of conversion capacity can be exercised at any time during the life of the project, subject to the demand for trade (see discussion on trade terms below).[3] Both designs have an operating life of 25 years (2017 – 2041), after an initial construction period of 4 years (2013 – 2017). The base costs are obtained from SNC-Lavalin and Parsons Brinckerhoff (2011). The unphased design is expected to have base costs of approximately USD 1 billion, whereas the phased design requires about USD 820 million in the first phase and an additional investment of 240 million as a second phase, if the option is exercised. O&M costs are assumed at 2% of total capital expenditure.

The phased design appears slightly more expensive in term of base costs, if it is definitively assumed that capacity will be added. However, the analysis described below shows a range of results.

Financing Terms and Assumptions

Financing costs are an important term in determining the cost annuity. The main terms and assumptions are summarized in Table 2.

Table 2. Financing Inputs for the Risk-based Valuation Model

Financing Terms and Assumptions for Valuation Model	
Type	Long-term debt with possible Capital Buydown
Initial Capital Buydown	0%
Lenders	Various, non-commercial
Debt Service Rate	Weighted average rate of 4% per annum
Tenor	20 years
Grace Period	5 years
Loan Commitment Fee	1% of CAPEX
Tax Rate	0%
Inflation Rate	0%
Required Project IRR	3%
Real Discount Rate	3%
Economic Life	29 years; 4 years construction + 25 years operating life

[3] In this regard, the financial valuation departs significantly from the feasibility studies. The previous studies all assume that the Phase 2 capacity addition option is necessarily exercised in 2020, irrespective of whether significant demand growth is realized.

Since the interconnection project is being donor-financed, the equity investment is assumed to be zero. The project structure is therefore long-term debt of a 20 year tenor with some fraction of a capital buydown received up front as a grant. The capital buydown effectively reduces the capital cost of the project. The all-in cost is quite sensitive to the fraction of cost bought down, as will be discussed in the results.

The lending terms include a grace period of 5 years after which principal and interest payments will begin. Since there may be more than one donor, a weighted average debt service rate of 4 % per annum is used, reflecting the low interest rates charged by development banks. The terms also include a loan commitment fee of 1%, payable as and when the capital is expended.

For the sake of simplicity, taxes and inflation are ignored, although these may have an impact on the cost annuity depending on prevailing tax rates and macro-economic forecasts. The inputs in the model can easily be changed to study the effect of taxes and inflation. In fact, decision makers may want to study the effect of available tax shields on overall project value.

The required project IRR is assumed to be low and equal to the risk-free discount rate. This assumption results in outputs that drive the project NPV to zero. If the IRR exceeds the discount rate, then the project is NPV positive, however it also implies a higher cost annuity and possibly higher tariff adders over the economic life of the project of almost three decades.

Trade Terms

As described earlier, revenues to the project have two sub-components – payments in accord with the PPA governing long-term trade in the line, and service charge payments from trade of surplus electricity in the short-term. Short-term trade refers to other energy flows in the line from short-term (not PPA) transaction between the two countries or flows of regional transactions between other countries that are transported through the line in question (wheeling flows). The assumptions regarding each of these components are summarized in Table 3.

The PPA is assumed to be in place for the entire operational life of the project of 25 years. The peak demand off-take is 300 MW at an annual average load factor of 80%. The effective amount of energy traded at this level is approximately 2,100 MWh/year. A bulk transmission tariff of US $20/MWh or 2 c/kWh is levied on trade through the PPA, conservatively selected to be below the differential in long-run marginal cost (LRMC) of generation between Ethiopia and Kenya.[4] This tariff level will not erode the incentive for Ethiopia to sell electricity to Kenya.

[4] The rationale is that trade will be profitable if the cost of trade, i.e. transmission tariff is less than the margin that can be earned by supplying electricity from lower-LRMC Ethiopia to higher LRMC Kenya. Thus, profits to generators from trade will still exceed the payments to the transmission entity.

Short-term trade of any surplus energy in the two systems is allowed to begin in 2021, in the fifth year after the line becomes operational. Because of generation projects expected to come online in other interconnected countries in the region, it is assumed that about 200 MW of peak power may be transferred through short-term trades at an average annual load factor of 40%. Short-term trade level is expected to grow at a conservatively low annual rate of 3% per annum, much lower than the expected 8 % per annum retail demand growth in both Ethiopia and Kenya. The access rate for short-term trades is assumed to be the same as the bulk tariff for the purpose of levying a service charge - $20/MWh.

Table 3. Trade Terms and Assumptions for the Risk-based Valuation Model

Trade Terms and Assumptions for Valuation Model	
Type	(1) Long-term Firm PPA; (2) Short-term Firm Trade of Surplus Energy
PPA Terms	
Contract Length	25 years
Demand	300 MW peak @ 80% average annual load factor
Effective Energy Trade	2,102 MWh/year
Bulk Tariff	US $ 20/MWh (2 c/kWh)
Surplus Trade Terms	
Start Date	2021, 5th year of operation
Initial Demand Level	200 MW
Growth Rate	3% p.a. (expected retail demand growth in Ethiopia & Kenya is 8% p.a.)
Access Rate	US $ 20/MWh (2 c/kWh)
Tariff Impact	
Country Allocation	50 % each to Ethiopia and Kenya
Retail Allocation	Postage stamp rate (c/kWh)

The missing money or tariff supplement realized annually is allocated equally to Ethiopia and Kenya. Because aggregate retail demand in each of the two systems differs, the postage stamp rate in the two systems is different. With lower retail demand, the Ethiopian tariff adder is generally expected to be higher as is demonstrated in the results.

Results

The two main output variables studied are the level of "missing money" or tariff supplement ($/year) required to maintain the equilibrium between the cost annuity and revenues, and the impact of end-use retail tariffs in the form of a tariff adder (c/kWh).

Result 1: **The PPA revenues cover only a small fraction of the cost annuity**. Figure 2 shows the annual cash flows of the project for a scenario without short-term surplus trade for the unphased design option (2000 MW upfront). For the assumptions described earlier, the PPA provides only USD 42 million (41%) of the cost annuity required to realize the project. The PPA revenue contribution increases to 52% for the phased option (Figure 3), because the capital costs incurred are lower – owing to the fact that additional conversion capacity of (1000 MW, USD 240 million) is never added in the absence of non-PPA trade.

Result 2: Even though the tariff supplement necessary to maintain cost annuity equilibrium is significant, the postage-stamped tariff adders in each system are very low. Figures 4 and 5 show the evolution of the tariff adder in both of Ethiopia and Kenya for the unphased and phased design options respectively. The incremental tariffs are highest at the beginning of project life, and decrease steadily over the project life as retail demand increases in each of the two systems, reaching the lowest level at the end of project life. The maximum tariff increment is about 0.45 c/kWh ($4.5/MWh), observed in Ethiopia for the unphased design. The tariff adders are lower for the phased design option. However, if retail tariffs are not increased in the two systems in for either design, the costs of the Interconnection will not be fully recovered. Further, the demand growth scenarios described here are deterministic. In reality, evolution in short-term trade will be volatile and tariffs will have to fluctuate to maintain the cost annuity equilibrium.

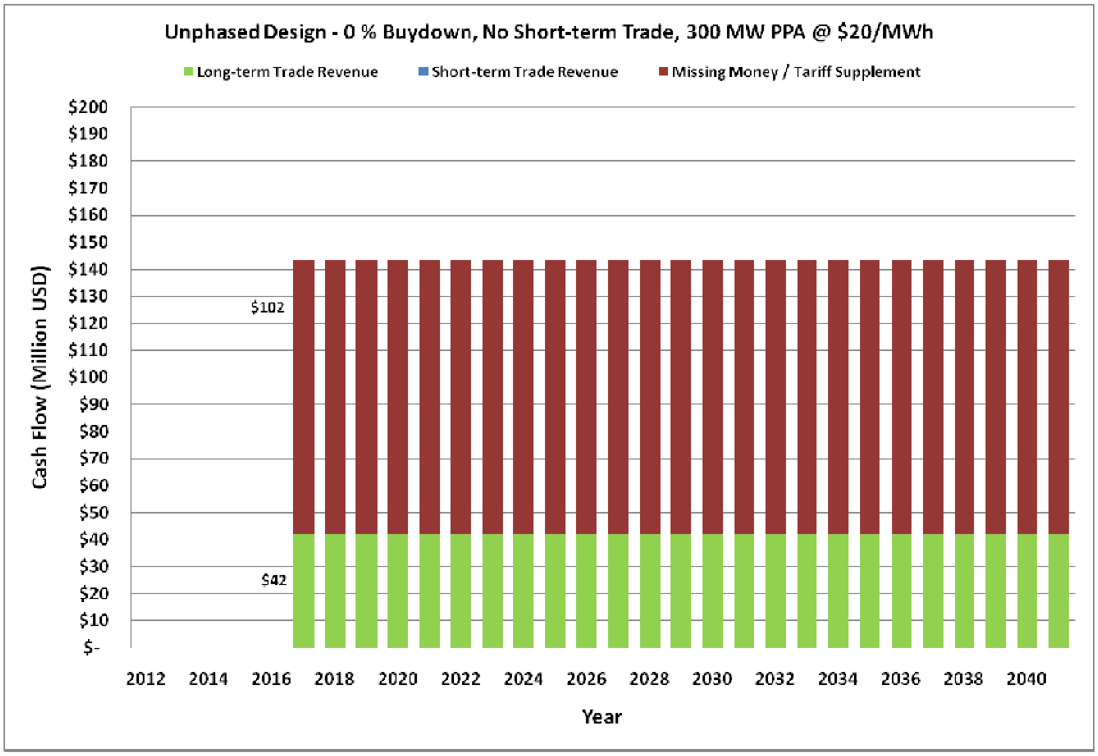

Figure 2. Cash Flows for Unphased Design Option – USD 102 million tariff supplement needed

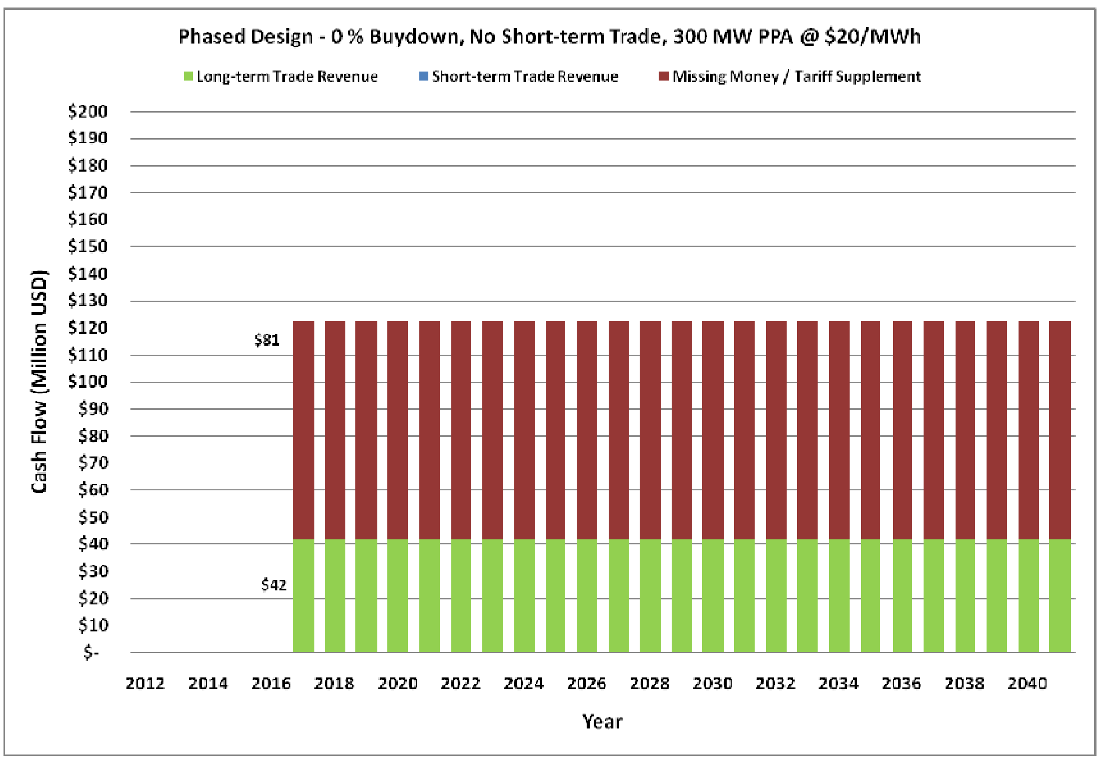

Figure 3. Cash Flows for Phased Design Option – USD 81 million tariff supplement needed

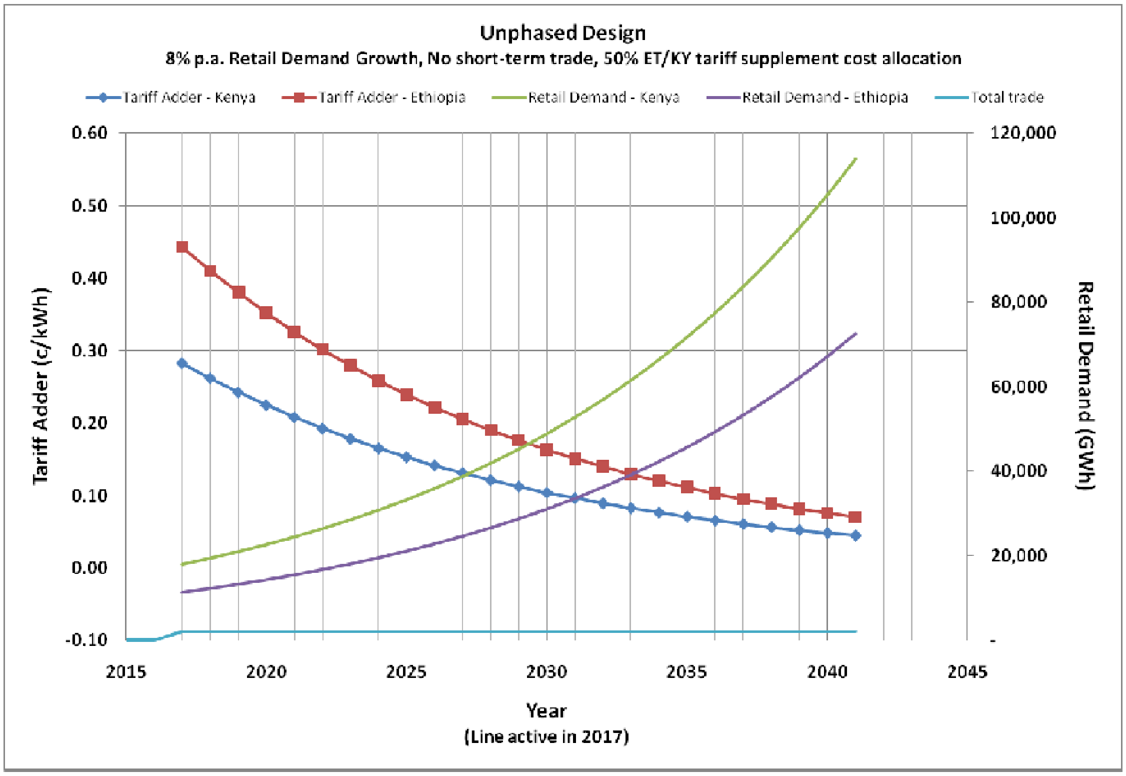

Figure 4. Unphased Design - Tariff Impact for assumed Retail Demand and PPA Trade over the project life

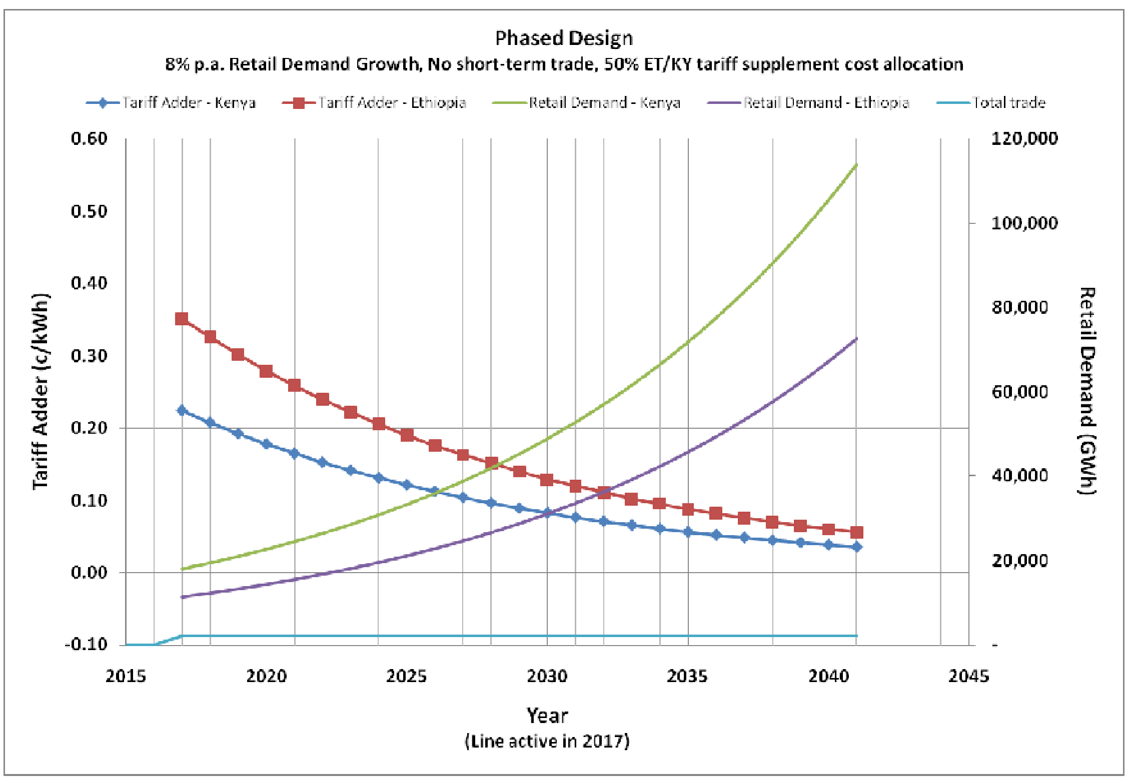

Figure 5. Phased Design - Tariff Impact for assumed Retail Demand and PPA Trade over the project life

Result 3: The tariff supplement required to maintain cost annuity equilibrium is highly sensitive to the level of PPA trade and the corresponding bulk tariff. Table 4 depicts a sensitivity analysis of the annual tariff supplement required as a function of PPA trade volume (ranging from 200 – 1000 MW @ 80% load factor) and bulk tariff (ranging from US $ 5 – 25/MWh) for different capital buydown levels and design options.

For example, consider the case described in the initial assumptions for a 0% capital buydown, 300 MW PPA at $20/MWh in the top-left matrix of the Table 4. The tariff supplement required to maintain cost annuity equilibrium is USD 102 million, corresponding to the scenario illustrated in Figure 2 earlier. In the same matrix, the supplement required decreases as the the level of tariff and trade increases in various combinations. The other matrices in the table can be read similarly.

Table 4. Sensitivity analysis of Tariff Supplement ($/year) to PPA trade volume and Bulk Tariff

0% Capital Buydown

Unphased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 110)	5	10	15	20	25
200	$ 137	$ 130	$ 123	$ 116	$ 109
300	$ 133	$ 123	$ 112	$ 102	$ 91
400	$ 130	$ 116	$ 102	$ 88	$ 74
600	$ 123	$ 102	$ 81	$ 60	$ 38
800	$ 116	$ 88	$ 60	$ 31	$ 3
1000	$ 109	$ 74	$ 38	$ 3	$ (32)

Phased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 87)	5	10	15	20	25
200	$ 116	$ 109	$ 102	$ 95	$ 88
300	$ 112	$ 102	$ 91	$ 81	$ 70
400	$ 109	$ 95	$ 81	$ 66	$ 52
600	$ 102	$ 81	$ 59	$ 38	$ 17
800	$ 95	$ 66	$ 38	$ 10	$ (18)
1000	$ 88	$ 52	$ 17	$ (18)	$ (53)

50% Capital Buydown

Unphased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 110)	5	10	15	20	25
200	$ 74	$ 67	$ 60	$ 53	$ 46
300	$ 71	$ 60	$ 50	$ 39	$ 29
400	$ 67	$ 53	$ 39	$ 25	$ 11
600	$ 60	$ 39	$ 18	$ (3)	$ (24)
800	$ 53	$ 25	$ (3)	$ (31)	$ (59)
1000	$ 46	$ 11	$ (24)	$ (59)	$ (94)

Phased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 87)	5	10	15	20	25
200	$ 65	$ 58	$ 51	$ 44	$ 37
300	$ 61	$ 51	$ 40	$ 30	$ 19
400	$ 58	$ 44	$ 30	$ 16	$ 2
600	$ 51	$ 30	$ 9	$ (12)	$ (33)
800	$ 44	$ 16	$ (12)	$ (40)	$ (69)
1000	$ 37	$ 2	$ (33)	$ (69)	$ (104)

100% Capital Buydown

Unphased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 110)	5	10	15	20	25
200	$ 13	$ 6	$ (1)	$ (8)	$ (15)
300	$ 9	$ (1)	$ (12)	$ (22)	$ (33)
400	$ 6	$ (8)	$ (22)	$ (36)	$ (50)
600	$ (1)	$ (22)	$ (43)	$ (64)	$ (85)
800	$ (8)	$ (36)	$ (64)	$ (92)	$ (120)
1000	$ (15)	$ (50)	$ (85)	$ (120)	$ (155)

Phased Design

Annual Peak Trade by Contract (MW, 80% LF) \ Bulk Tariff ($/MWh) ($ 87)	5	10	15	20	25
200	$ 14	$ 7	$ 0	$ (7)	$ (14)
300	$ 11	$ 0	$ (10)	$ (21)	$ (31)
400	$ 7	$ (7)	$ (21)	$ (35)	$ (49)
600	$ 0	$ (21)	$ (42)	$ (63)	$ (84)
800	$ (7)	$ (35)	$ (63)	$ (91)	$ (119)
1000	$ (14)	$ (49)	$ (84)	$ (119)	$ (154)

In Table 4, the matrices on the left illustrate the tariff supplement required for the unphased design option, while those on the right indicate those for the phased design option. Without short term trade, the phased design is always "cheaper" in terms of the required tariff supplement because less capital is being expended, since the needed to add capacity never arises. In one sense, the unphased design is simply oversized because the level of PPA trade may always be low. On the other hand, having the phased flexible design option provides the same transfer capacity in the event that it is needed in the future. The valuation of flexibility is discussed further in Result 6.

Even in the absence of non-PPA short-term trade it is possible to recover the cost annuity for some combinations of high trade volumes and high tariffs (shown in green), for both design options. In some scenarios, PPA revenues may exceed the annuity, resulting in a negative tariff supplement. In general, there is an efficient frontier of combinations of trade volumes and tariffs that will result in full cost recovery from PPA revenues. However, a high tariff may discourage trade, while the systems may not be able to maintain a high volume of firm delivery as contracted in the PPA if specified volumes are too high.

Result 4: The tariff supplement required is extremely sensitive to the fraction of capital costs bought down. Increasing the fraction of capital cost buydown (proceeding down the rows in Table 4 from 0%, 50%, 100%) indicates that the tariff supplement required decreases dramatically across all combinations of the trade and tariff levels. The implication is that the costs of the Interconnection will have to be subsidized through the capital buydown, if the impact on tariffs is to be mitigated.

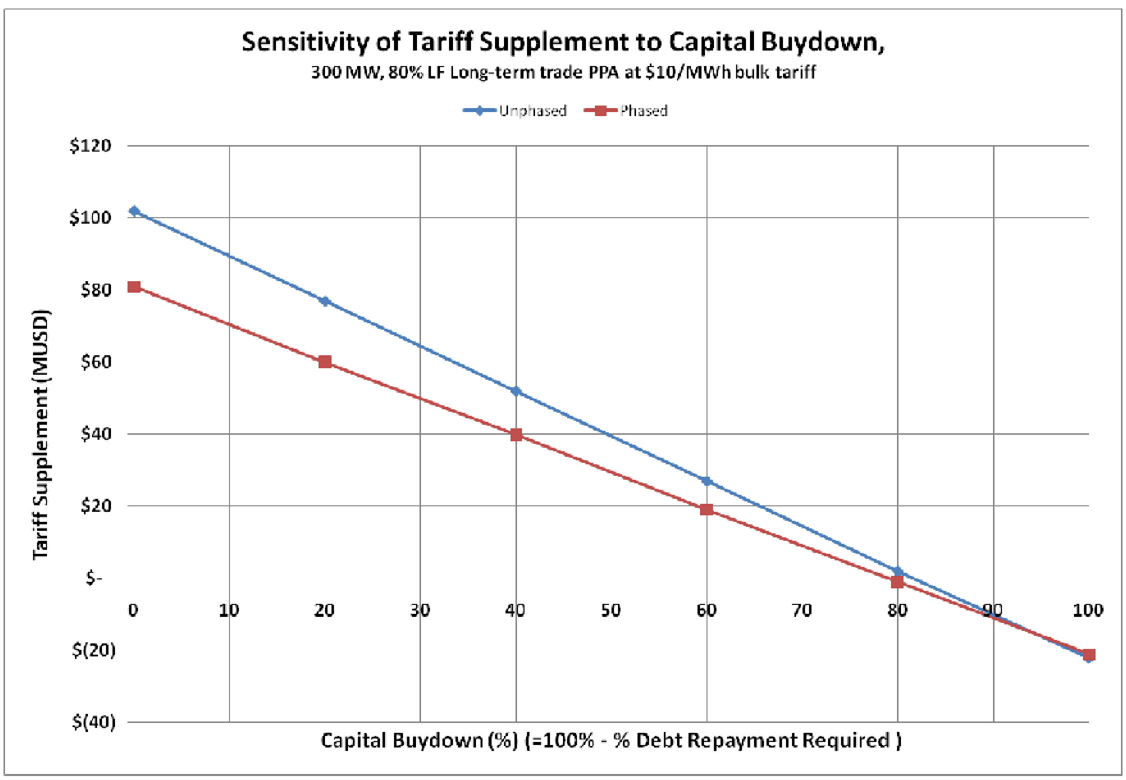

Figure 6. Variation in Tariff Supplement as a function of Capital Buydown

For the example scenario discussed earlier (300 MW PPA at $20/MWh), the effect of the fraction of capital buydown on tariff supplement required is shown in Figure 6 for both design options. Going from 0% to 100%, the tariff supplement falls from USD 102 million to (21) million for the unphased design and from USD 81 million to (21) million for the phased design. The lines cross the zero level of tariff supplement at 80% capital buydown. In other words, the revenues from the long-term PPA are sufficient to break even at the 80% level of capital buydown. Negative values of the tariff supplement for buydown greater than 80% imply a surplus realized from trade revenues.

Result 5. Low levels and growth rates in short-term trade of energy reduce the tariff supplement moderately but are far from sufficient to eliminate the tariff supplement. For short-term trade beginning in 2021 at an initial level of 200 MW with a growth rate of 3 % p.a., the tariff supplement required gradually reduces from USD 102 million to USD 76 million by 2041 for the unphased design (Figure 7). For the phased design, the requirement gradually reduces from USD 81 million to USD 55 million by 2041. The "missing money" to reach cost annuity equilibrium is thus always large for realistically low growth rates in short term trade.

If a much higher 8% p.a. growth rate in short-term trade is assumed, the same as expected retail demand growth in Ethiopia and Kenya, an approximately 30% capital buydown is required to eventually reach cost annuity equilibrium for the unphased design and 20% buydown for the phased design as shown in Figures 9 and 10. Alternatively, additional PPAs can be entered into after the line enters service instead of a capital buydown to realize the cost annuity equilibrium.

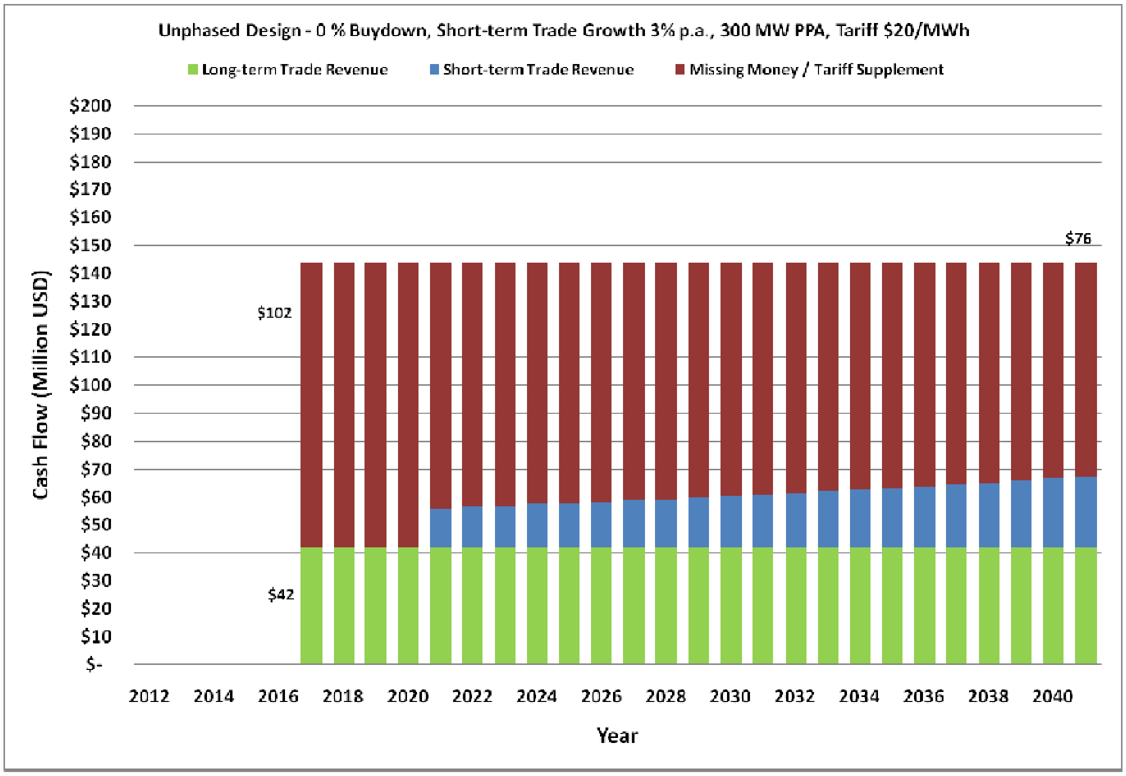

Figure 7. Unphased design – Short-term Trade is not sufficient to realize Cost Annuity Equilibrium

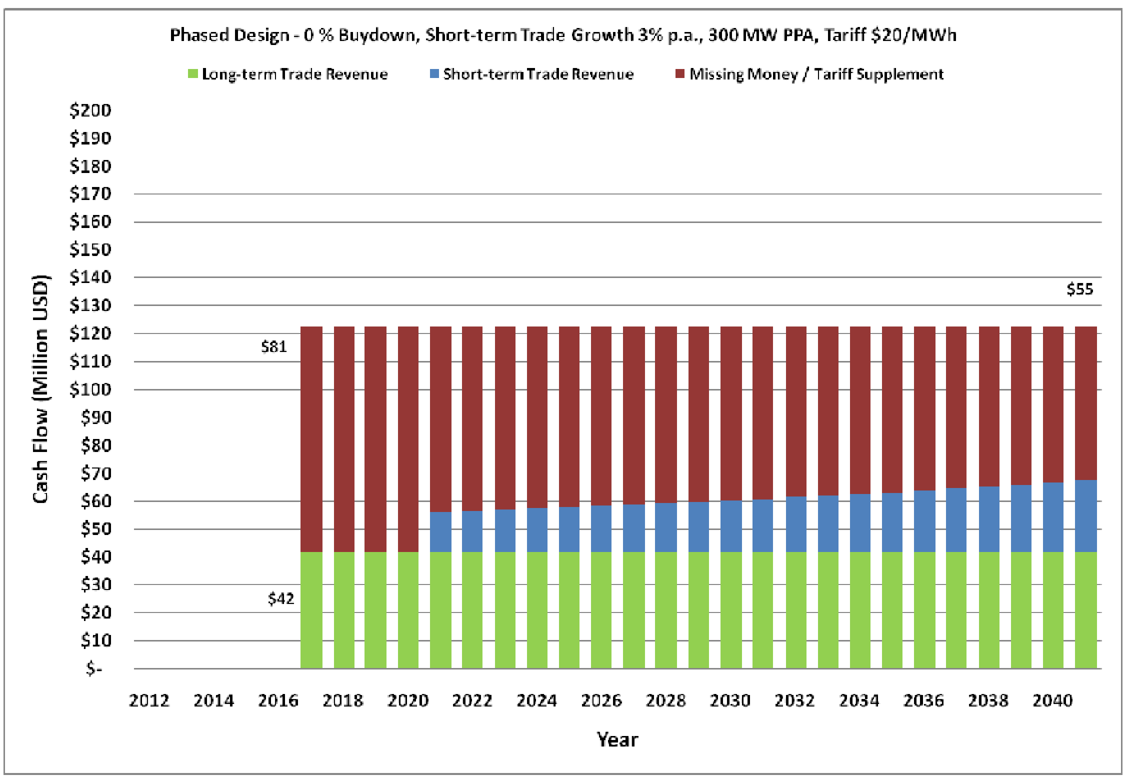

Figure 8. Phased design – Short-term Trade is not sufficient to realize Cost Annuity Equilibrium

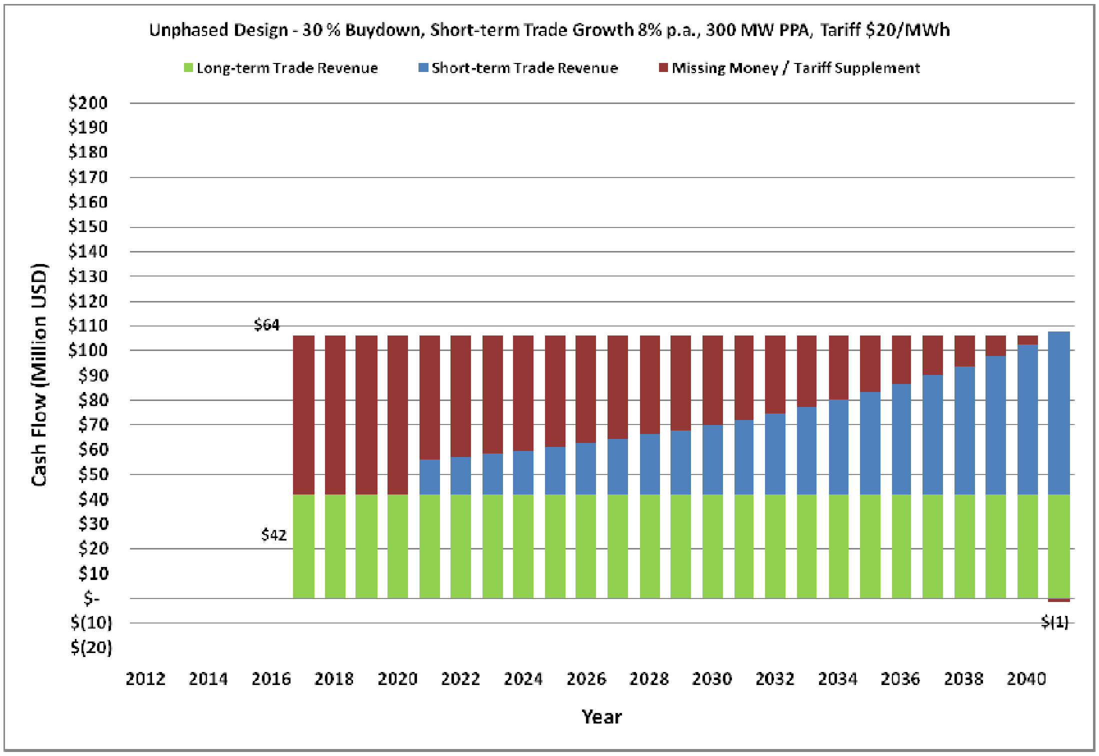

Figure 9. Unphased Design - 30 % Capital Buydown needed to eventually eliminate tariff supplement for 8 % p.a. Short-term Trade Growth

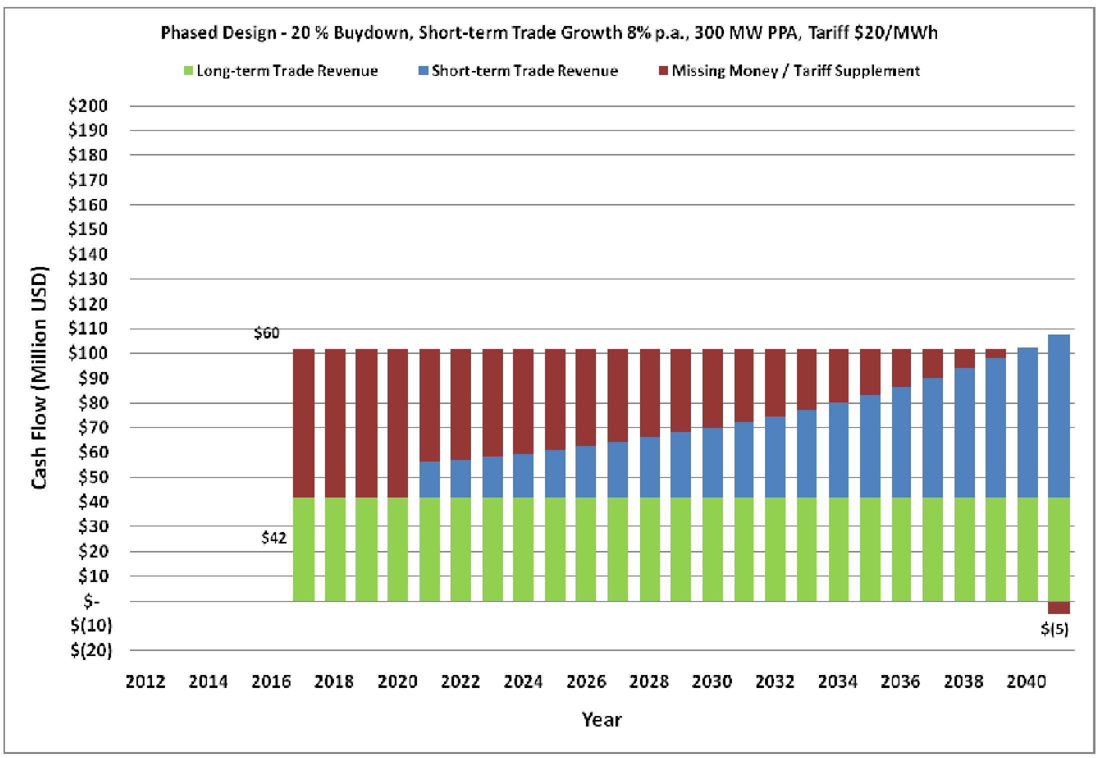

Figure 10. Phased Design - 20 % Capital Buydown needed to eventually eliminate tariff supplement for 8 % p.a. Short-term Trade Growth

Result 6. A very high level of PPA trade is required at low bulk tariff levels for the Interconnection to be financially viable. Without any capital buydown and a 3% p.a. growth in short-term trade, an 800 MW PPA is needed at a tariff of $20/MWh to almost eliminate the tariff supplement by the end of project life for the unphased design, as shown in Figure 11. The required PPA trade level falls to 700 MW for the phased design option (Figure 12). The annual tariff supplement required reduces from USD 31 million at the beginning of project life to USD 6 million in 2041 for the unphased design option and from USD 24 million to USD (1) million for the phased option for the PPAs with high trade levels of 800 MW and 700 MW respectively.

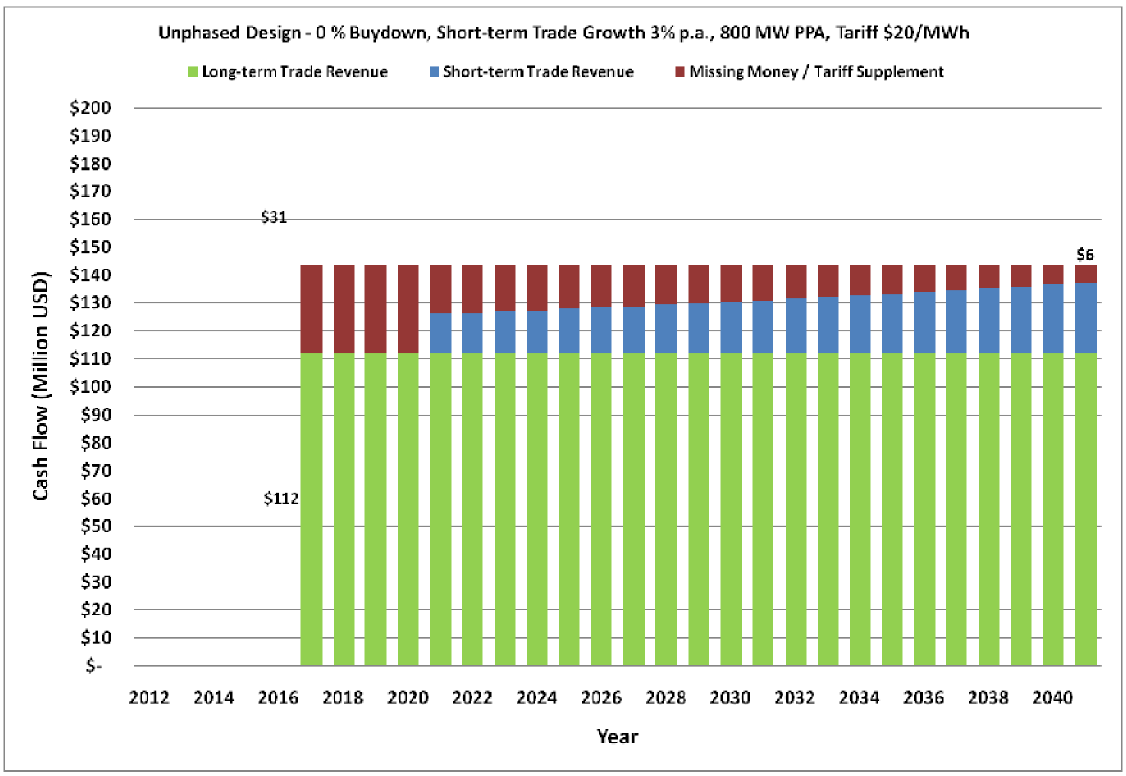

Figure 11. Unphased Design- 800 MW PPA required to almost eliminate tariff supplement with 3% short term trade growth

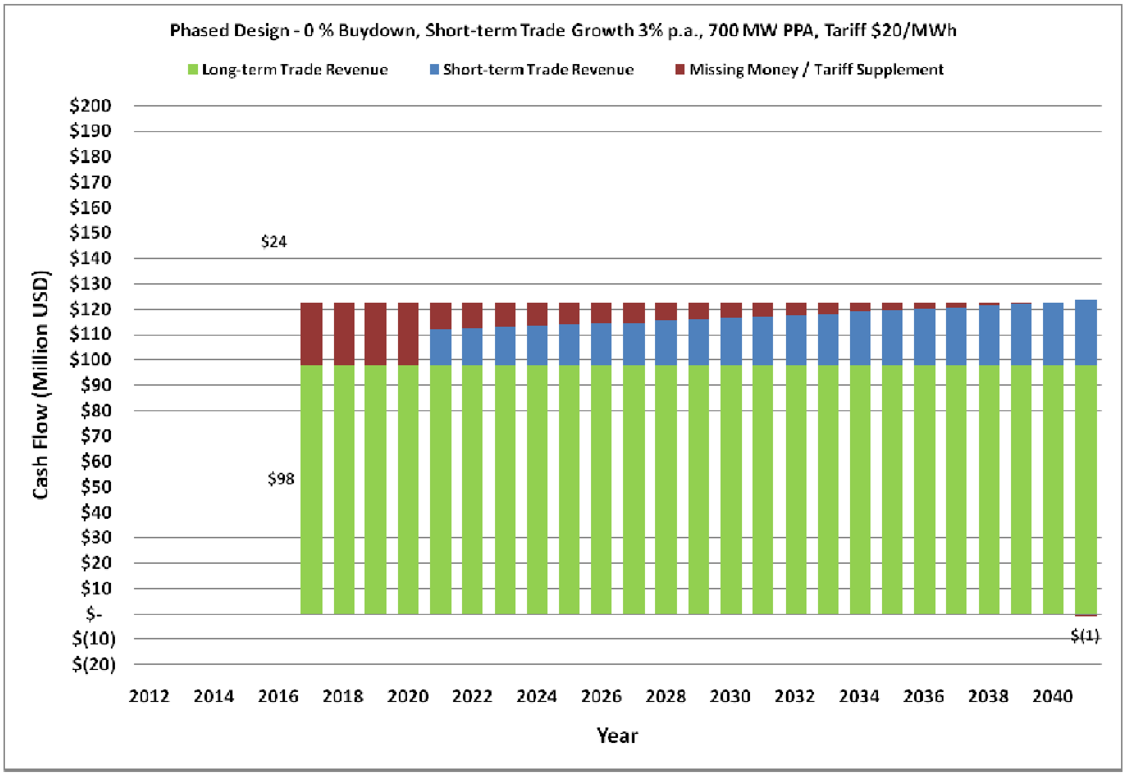

Figure 12. Phased design - 700 MW PPA required to eliminate tariff supplement with 3% short term trade growth

Result 7: The phased design is the most valuable design option under both low and high levels of trade. As shown in Table 4 and Figures 7 - 12, the tariff supplement required is always lower for the phased design than for the unphased design, primarily because excess capacity is avoided. For the 300 MW PPA at $20/MWh with no capital buydown, the value of the phased design is USD (144 - 123) = 21 million per year in all scenarios when the total trade does not exceed a 1000 MW of capacity during the project's lifetime. In the phased design, capacity is added only in the event that an extremely high demand for trade is realized, as shown in Figure 13. In this illustrative scenario, the cumulative level of PPAs is assumed to be 600 MW, over and above which short term trade is realized beginning at 200 MW at a growth rate of 8% p.a., the same as expected retail demand growth. Trade levels therefore exceed that supported by the initial capacity of 1000 MW before the end of project life, resulting in an investment of USD 240 million to add another 1000 MW of conversion capacity. The cost annuity over the entire life of the project therefore rises accordingly. For the scenario described, the incremental cost to enable the additional 1000 MW of capacity is only USD (131 – 123) = 8 million per year. This incremental cost is the "exercise price" of the option to be able to support high levels of trade upto 2000 MW. Even with the additional investment, the cost annuity is still USD (144 – 131) = 13 million less than that of the unphased design option.

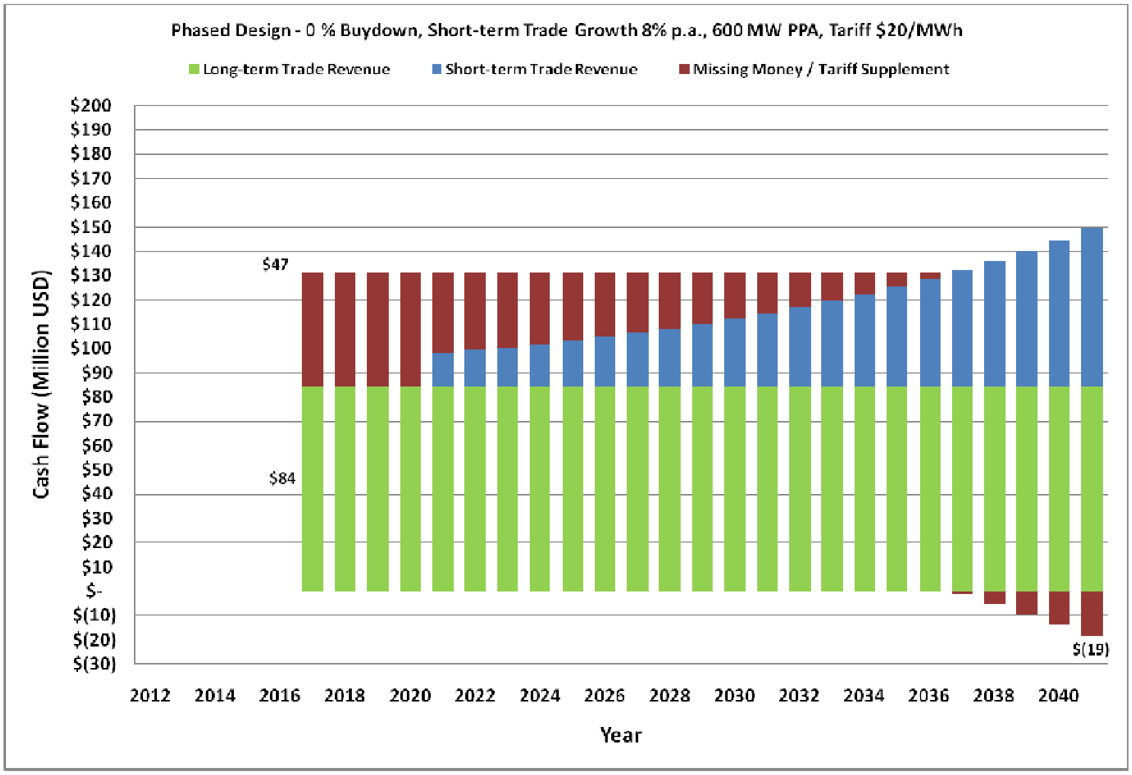

Figure 13. Phased design enables late capacity addition at lower cost annuity than unphased design and supports substantially higher levels of trade